

November 2, 2000

Mr. James Reede
California Energy Commission
1516 9th Street
Sacramento, CA 95814-5512

Dear Mr. Reede:

The South Coast Air Quality Management District (AQMD) has modified our review of the proposed expansion of Mountainview Power, LLC's facility located in the city of San Bernardino. As such, staff has prepared a revised engineering analysis and evaluation of the expansion with respect to all AQMD, State, and Federal rules applicable. Our enclosed analysis shall be considered as CEC's Preliminary Determination of Compliance (PDOC) from the AQMD and replaces the respective documents sent to you on October 20, 2000. Enclosed with PDOC are supporting documents including:

- AQMD's PDOC
- Draft Title V and AQMD RECLAIM Permit, Section H

The draft permit includes copies of sections E, F, G, and K as these sections contain conditions applicable to the entire facility including administrative, RECLAIM monitoring and source testing, RECLAIM record keeping, and Title V administrative conditions.

This project is considered a "Significant revision" to Mountainview's Title V Facility permit. As such, the AQMD is required under Rule 3005 (f)(2) to provide a copy of the proposed permit to the EPA Administrator for a 45-day review. In addition, the AQMD is required to complete a public notice which provides at least 30 days for public comment. Both of these tasks will be undertaken shortly and must be completed before the AQMD issues a final permit to construct. If you have any questions or wish to provide comments regarding this project, please call Mr. Chris Perri (909) 396-2696 or Mr. John Yee (909) 396-2531.

Very truly yours,

Pang Mueller
Senior Manager
Refinery, Energy, and RECLAIM Administration
Engineering and Compliance

Attachments
JTY:mvpdoc2.doc

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PERMIT TO CONSTRUCT

COMPANY NAME AND ADDRESS:

Mountainview Power, LLC
25770 San Bernardino Ave.
San Bernardino, CA 92408

SCAQMD ID# 121737

EQUIPMENT DESCRIPTION:

Section H of the Mountainview Facility Permit, ID# 121737

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
Process 6: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
TURBINE, GAS, NO. 3-1, NATURAL GAS, GE, MODEL 7FA, COMBINED CYCLE, WITH DRY LOW NOX COMBUSTORS, 1,991 MMBTU/HR, WITH A/N: 366147	D18	C23, C24, S35	NOX: MAJOR SOURCE	NOX: 2.5 PPMV (4) [RULE 2005]; NOX: 2 PPMV (7) [RULE 2005]; NOX 87.9 PPMV (8) [40CFR 60 SUBPART GG]; NOX: 32 LBS/MMSCF (1) [RULE 2012]; NOX: 64 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 356 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 75.15 LBS/HR (4) [RULE 2005]; CO: 6 PPMV (4) [RULE 1303 BACT]; CO: 2000 PPMV (5) [RULE 407]; VOC: 1.4 PPMV (4) [RULE 1303-BACT]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475];	1-1, 28-1, 28-2, 40-1, 57-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 99-4, 99-5, 99-6, 99-7, 195-1, 195-2, 195-4, 327-1, 372-1

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GENERATOR, 175.7 MW	(B19)			SOX: 150 PPMV (8) [40CFR 60 SUBPART GG] SO2: (9) [40CFR 72 – ACID RAIN]	
GENERATOR, HEAT RECOVERY STEAM	(B20)				
BURNER, DUCT, 135 MMBTU/HR	D21			NOX: 130 LBS/MMSCF (1) [RULE 2012]	
TURBINE, STEAM, COMMON WITH TURBINE 3-2, , 214.5 MW	(B22)				
SELECTIVE CATALYTIC REDUCTION, NO. 3-1, WITH 2750 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 72 FT; LENGTH: 1.5 FT; WIDTH 25.6 FT; WITH A/N 366151	C24	D18		NH3: 5 PPMV (4) [RULE 1303-BACT]	12-1, 12-2, 179-1, 179- 2, 195-3
AMMONIA INJECTION, INJECTION GRID	(B25)				
CO OXIDATION CATALYST, NO. 3-1, WITH 240 CUBIC FEET OF TOTAL CATALYST VOLUME A/N 366151	C23	D18			
TURBINE, COMBINED CYCLE, NO. 3-2, NATURAL GAS, GE, MODEL 7FA, 1,991 MMBTU/HR, WITH A/N: 366148	D27	C32, C33, S35	NOX: MAJOR SOURCE	NOX: 2.5 PPMV (4) [RULE 2005]; NOX: 2 PPMV (7) [RULE 2005]; NOX 87.9 PPMV (8) [40CFR 60 SUBPART GG]; NOX: 32 LBS/MMSCF (1) [RULE 2012]; NOX: 64 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 356 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 75.15 LBS/HR (4) [RULE 2005]; CO: 6 PPMV (4) [RULE 1303 BACT]; CO: 2000	1-1, 28-1, 28-2, 40-1, 57-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 99-4, 99-5, 99-6, 99-7, 195-1, 195- 2, 195-4, 327-1, 372- 1

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GENERATOR, 175.7 MW	(B28)			PPMV (5) [RULE 407]; VOC: 1.4 PPMV (4) [RULE 1303-BACT]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; SOX: 150 PPMV (8) [40CFR 60 SUBPART GG] SO2: (9) [40CFR 72 – ACID RAIN]	
GENERATOR, HEAT RECOVERY STEAM	(B29)				
BURNER, DUCT, 135 MMBTU/HR	D30			NOX: 130 LBS/MMSCF [RULE 2012] (1)	
TURBINE, STEAM, COMMON WITH TURBINE 3-1, 214.5 MW	(B31)				
SELECTIVE CATALYTIC REDUCTION, NO. 3-2, WITH 2750 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 72 FT; LENGTH: 1.5 FT; WIDTH 25.6 FT; WITH A/N 366152	C33	D27		NH3: 5 PPMV (4) [RULE 1303-BACT]	12-1, 179- 1, 179-2, 195-3
AMMONIA INJECTION, INJECTION GRID	(B34)				
CO OXIDATION CATALYST, NO. 3-2, WITH 240 CUBIC FEET OF TOTAL CATALYST VOLUME A/N 366152	C32	D27			
STACK, NO. 3-1/3-2 A/N: 366146	S35	D18, D27			
TURBINE, COMBINED CYCLE, NO. 4-3, NATURAL GAS, GE, MODEL 7FA, 1,991 MMBTU/HR, WITH A/N: 366149	D36	C41, C42, S53	NOX: MAJOR SOURCE	NOX: 2.5 PPMV (4) [RULE 2005]; NOX: 2 PPMV (7) [RULE 2005]; NOX 87.9 PPMV (8) [40CFR 60 SUBPART GG]; NOX: 32 LBS/MMSCF (1) [RULE	1-1, 28-1, 28-2, 40-1, 57-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 99-4, 99-5,

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GENERATOR, 175.7 MW	(B37)			2012]; NOX: 64 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 356 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 75.15 LBS/HR (4) [RULE 2005]; CO: 6 PPMV (4) [RULE 1303 BACT]; CO: 2000 PPMV (5) [RULE 407]; VOC: 1.4 PPMV (4) [RULE 1303-BACT]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; SOX: 150 PPMV (8) [40CFR 60 SUBPART GG] SO2: (9) [40CFR 72 – ACID RAIN]	99-6, 99-7, 195-1, 195-2, 195-4, 327-1, 372-1
GENERATOR, HEAT RECOVERY STEAM	(B38)				
BURNER, DUCT, 135 MMBTU/HR	D39			NOX: 130 LBS/MMSCF [RULE 2012] (1)	
TURBINE, STEAM, COMMON WITH TURBINE 4-4, 214.5 MW	(B40)				
SELECTIVE CATALYTIC REDUCTION, NO. 4-3, WITH 2750 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 72 FT; LENGTH: 1.5 FT; WIDTH 25.6 FT; WITH A/N 366153	C42	D36		NH3: 5 PPMV (4) [RULE 1303-BACT]	12-1, 179-1, 179-2, 195-3
AMMONIA INJECTION, INJECTION GRID	(B43)				
CO OXIDATION CATALYST, NO. 4-3, WITH 240 CUBIC FEET OF TOTAL CATALYST VOLUME A/N 366153	C41	D36			
TURBINE, COMBINED	D45	C50, C51,	NOX:	NOX: 2.5 PPMV (4)	1-1, 28-1,

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CYCLE, NO. 4-4, NATURAL GAS, GE, MODEL 7FA, 1,991 MMBTU/HR, WITH A/N: 366150		S53	MAJOR SOURCE	[RULE 2005]; NOX: 2 PPMV (7) [RULE 2005]; NOX 87.9 PPMV (8) [40CFR 60 SUBPART GG]; NOX: 32 LBS/MMSCF (1) [RULE 2012]; NOX: 64 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 356 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 75.15 LBS/HR (4) [RULE 2005]; CO: 6 PPMV (4) [RULE 1303 BACT]; CO: 2000 PPMV (5) [RULE 407]; VOC: 1.4 PPMV (4) [RULE 1303-BACT]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; SOX: 150 PPMV (8) [40CFR 60 SUBPART GG] SO2: (9) [40CFR 72 – ACID RAIN]	28-2, 40-1, 57-1, 63-1, 67-1, 82-1, 82-2, 99-1, 99-2, 99-3, 99-4, 99-5, 99-6, 99-7, 195-1, 195-2, 195-4, 327-1, 372-1
GENERATOR, 175.7 MW	(B46)				
GENERATOR, HEAT RECOVERY STEAM	(B47)				
BURNER, DUCT, 135 MMBTU/HR	D48			NOX: 130 LBS/MMSCF [RULE 2012] (1)	
TURBINE, STEAM, COMMON WITH TURBINE 4-3, 214.5 MW	(B49)				
SELECTIVE CATALYTIC REDUCTION, NO. 4-4, WITH 2750 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 72 FT; LENGTH: 1.5 FT; WIDTH 25.6 FT; WITH A/N 366154	C51	D45		NH3: 5 PPMV (4) [RULE 1303-BACT]	12-1, 179-1, 179-2, 195-3
AMMONIA INJECTION, INJECTION GRID	(B52)				
CO OXIDATION CATALYST.	C50	D45			

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NO. 4-4, WITH 240 CUBIC FEET OF TOTAL CATALYST VOLUME A/N 366153					
STACK, NO. 4-3/4-4 A/N: 366149	S53	D36, D45			
SYSTEM 2: DIESEL ENGINES					
INTERNAL COMBUSTION ENGINE, EMERGENCY POWER, DIESEL, CATERPILLAR, 3612, 4° TIMING RETARD, TURBOCHARGED AFTERCOOLED, 5900 BHP A/N: 366155	D54		NOX: PROCESS UNIT	NOX: 6.9 GR/BHPH (4) [RULE 2005-BACT] CO: 8.5 GR/BHPH (4) [RULE 1303-BACT]; VOC (4) 1.0 GR/BHPH (4) [RULE 1303-BACT]; PM10: 0.38 GR/BHPH (4) [RULE 1303 – BACT]; NOX: 469 LBS/1000 GAL (1) [RULE 2012]	1-1, 12-3, 67-2, 162-1, 177-1
INTERNAL COMBUSTION ENGINE, EMERGENCY FIRE, DIESEL, CUMMINS, 6BTA, TURBOCHARGED, AFTERCOOLED, TIMING RETARD, 182 BHP A/N: 366156	D55		NOX: PROCESS UNIT	NOX: 6.9 GR/BHPH (4) [RULE 2005-BACT] CO: 8.5 GR/BHPH (4) [RULE 1303-BACT]; VOC (4) 1.0 GR/BHPH (4) [RULE 1303-BACT]; PM10: 0.38 GR/BHPH (4) [RULE 1303 – BACT]; NOX: 469 LBS/1000 GAL (1) [RULE 2012]	1-1, 12-3, 67-2, 177-1
PROCESS 7: AMMONIA STORAGE					
STORAGE TANK, TK-1, SERVING SCR'S 3-1 AND 3-2, WITH A VAPOR RETURN LINE, AQUEOUS AMMONIA, 24.5% SOLUTION, 22,500 GALLONS A/N: 366162	D56				144-1, 157-1
STORAGE TANK, TK-2, SERVING SCR'S 4-3 AND 4-4, WITH A VAPOR RETURN LINE, AQUEOUS AMMONIA, 24.5% SOLUTION, 22,500 GALLONS A/N: 366163	D57				144-1, 157-1

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EQUIPMENT LOCATION:

25770 San Bernardino Ave.
San Bernardino, CA 92408

COMPLIANCE RECORD REVIEW

A check of the AQMD Compliance Database shows there are no violation notices issued to this facility in the past 2 years.

BACKGROUND:

Existing Plant

Mountainview Power operates a power generating facility in an unincorporated area near the city of San Bernardino California, which they purchased from Southern California Edison in 1998. Currently the facility consists of 2 natural gas fired boilers each with a steam turbine generator. Each boiler/turbine system has a nominal rating of 66 MW gross and 63 MW net power output. The units are served by 2 existing cooling towers. Boilers 1 and 2 presently operate under AQMD permits F31692 (A/N 372768) and F31693 (A/N 368334) respectively. The boilers are currently being modified to add water injection control systems under A/N's 372767 and 372768. A Title V permit is expected to be issued shortly, pending an EPA review. The addition of water injection will reduce NOx emissions from these boilers, with no associated increase in any other pollutant. The addition of the water injection is considered a separate project from the expansion project.

New Turbines

Mountainview has proposed to expand their facility with the addition of 4 new combined cycle GE 7FA gas turbine engines equipped with duct burners and evaporative coolers. Each turbine is nominally rated at 166.7 MW gross power generation, and is equipped with a auxiliary-fired heat recovery steam generator (HRSG) to recover waste heat from the turbine exhaust gases. Duct burners in the HRSG are rated at 135 mmbtu/hr. The turbines are paired into 2 power blocks, with each block served by 1 steam turbine receiving steam from a pair of HRSGs. Each steam turbine is rated at 209.2 MW gross. There will be 2 new cooling towers, (also the 2 exiting towers for Boilers 1 and 2 will be rebuilt). Cooling towers for the new turbines are each rated at 147,000 gpm and will consist of 10 cells per tower. Total nominal out put from the new turbine/duct burners

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and steam turbines is 1,085.2 MW gross and 1,055.9 MW net. Table 15 in Appendix A shows expected output for the new plant plus the existing boilers.

Control Systems

Emission controls will consist of Dry LowNO_x (DLN) combustors, SCR systems and CO catalysts. The SCRs will control NO_x emissions to a level not to exceed of 2.5 ppm (at 15% O₂) on a 1 hour average basis. CO emissions will be controlled to 6 ppm (15% O₂) 1 hour average, with the use of a CO oxidation catalyst.

The existing boilers will remain in operation however, one of their main purposes after installation of the turbines will be to provide heat to the SCR catalyst during turbine start-ups. This will allow immediate use of the SCR control system upon start-up of the turbines, and minimize the typical interim time period during which there is no control while the SCR catalyst reaches operating temperature.

The following table shows corresponding A/N's for the project:

TABLE 1 – AQMD Application Numbers

A/N	Equipment
366147	Turbine #3-1
366148	Turbine #3-2
366149	Turbine #4-3
366150	Turbine #4-4
366151	SCR #3-1
366152	SCR #3-2
366153	SCR #4-3
366154	SCR #4-4
366155	Diesel Emergency Generator
366156	Diesel Emergency Fire
366162	Aqueous Ammonia Storage Tank 1
366163	Aqueous Ammonia Storage Tank 2

The applications were deemed complete by the AQMD on April 12, 2000. Note that the following evaluation pertains mainly to the gas turbines and associated control equipment, but considers the diesel engines where appropriate (i.e. PSD modeling includes the diesel engine emissions). A description of the engines and ammonia tanks, associated emission limits, and conditions are included here for reference, however the files corresponding to the above application numbers contain the NSR evaluations

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specific to the engines and tanks. These files should be referred to for more detailed information on that equipment.

PROCESS DESCRIPTION:

Turbine operation is characterized by 3 basic modes of operation, baseload, peak load, and cyclic load. The Mountainview plant is designed to operate in all 3 modes. It is projected that at certain times of the year, the plant will “sell forward” base load power generation. At other times, the plant may operate on a cyclic load, and sell power during selected periods of the day and week. Finally, the units will be designed for peaking operation where the use of duct burners will allow increased generation during high demand periods.

TABLE 2 - Gas Turbine/HRSG Specs

Specification	
Manufacturer	GE
Model	7FA
Fuel Type	Pipeline Natural Gas
Maximum Fuel Consumption	2.11 mmcf/hr (includes DB)
Maximum GT exhaust flow	60 mmcf/hr
Gas Turbine Heat Input	1,991 mmbtu/hr maximum
Duct Burner Heat Input	135 mmbtu/hr maximum
Maximum Gas Turbine Output	175.7 MW gross
Maximum Steam Turbine Output	214.5 MW gross
Net Plant Heat Rate, LHV	6,327 Btu/kw-hr
Net Plant Heat Rate, HHV	7,023 Btu/kw-hr
Net Plant Efficiency	53.95%

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TABLE 3 - Selective Catalytic Reduction Specs

Specification	
Manufacturer	Mitsubishi
Catalyst Type	honeycomb or plate-type
Catalyst Volume	2,750 ft ³
Space Velocity	16,500 hr ⁻¹
Area Velocity	130 ft/hr
Ammonia Injection Rate	153 lbs/hr of 24.5 wt. percent aqueous ammonia
Ammonia Slip	5 ppm at 15% O ₂ (15 minute avg)
Outlet NO _x	2.5 ppm (1 hour avg), 1.0 ppm (annual avg) at 15% O ₂
SCR Unit Total Cost	\$1.6 million per unit

TABLE 4 - CO Catalyst Specs

Specification	
Manufacturer	Mitsubishi
Catalyst Type	Corrugated stainless steel substrate, coated with platinum group metals impregnated alumina washcoat
Catalyst Volume	240 ft ³
Space Velocity	200,000 hr ⁻¹
Outlet CO	6 ppm (1 hour avg), 2.0 ppm (annual average) at 15% O ₂
Outlet VOC	1.4 ppm (1 hour average) at 15% O ₂
CO Catalyst Total Cost	\$714,000
Catalyst Replacement Cost	\$350,000

Cooling Towers

Two new cooling towers will provide heat rejection for the new turbines. Each tower is rated at 147,000 gallons per minute, and will use reclaimed water. The design drift rate (entrained water droplets entrained in the warm air leaving the tower) is 0.0006 percent of the circulating water flow. The cooling towers are exempt from AQMD permitting (see further discussion under 'Emissions' section to follow).

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Support Equipment

Support equipment for the facility includes a 5,900 hp emergency diesel generator which will provide back-up power for the plant in case of an outage (A/N 366155). The facility also plans to install a 182 hp emergency fire pump engine (A/N 366156). A NSR evaluation for permitting purposes is conducted for this equipment under their respective applications.

There will also be two ammonia storage tanks serving the turbine SCR's. Refer to A/N's 366162 and 366163 for a permit evaluation for the tanks.

The plant will also include the following storage tanks, which are exempt for AQMD permitting requirements:

- Demineralized water storage
- Emergency diesel generator oil storage
- Fire protection diesel oil storage
- Clean lubricating oil storage
- Dirty lubricating oil storage

Existing Boilers

The Mountainview facility currently consists of 2 boiler/steam turbine generators, each rated at 63 MW net power output. The boilers are identical Combustion Engineering units fired on natural gas exclusively. Presently, the boilers operate mainly during peak summer months only. After installation of the new gas turbines, Mountainview plans to use steam from the existing boilers to pre-heat the SCR catalyst control systems for the turbines. This will allow NOx control of the turbine exhaust during start up conditions.

EMISSIONS:

Emissions from the gas turbines are affected by several factors, including mode of operation, use of duct burners, and ambient meteorological conditions. The two basic operational modes affecting emissions are start-up and baseload operation (including peak load). Start-ups are defined as "hot", "warm", or "cold", depending on how long the start up lasts, which in turn is dependant on how long the turbine was shut down before the start-up. A hot start lasts for 1 hour, and occurs after the turbine has been down for 8 hours or less. Similarly, a warm start occurs after 8-48 hours of shutdown, and lasts 2 hours, and a cold start occurs after more than 72 hours of shutdown, and lasts 3 hours. Because the plant will be a merchant power producer, market demand will mostly dictate exactly how often and when the plant operates over the course of a year. This will affect

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the emission estimates by affecting the number of start-ups, and the hours of baseload operation.

For AQMD New Source Review emission offset and BACT purposes, maximum and average daily emissions on a per turbine basis need to be considered for those pollutants not subject to RECLAIM. RECLAIM NO_x is evaluated for all four turbines on an annual basis in determining the necessary RECLAIM Trading Credits (RTCs). Additionally, to determine air quality impacts from a modeling perspective, maximum plant-wide emissions from the operation of all new equipment subject to NSR, which in this case includes only the 4 new turbines are considered on an hourly, daily, and annual basis. And, as part of a broader modeling analysis done under the AFC process, Mountainview has done additional modeling of plant-wide emissions in which sources such as the existing boilers and cooling towers, as well as the new cooling towers and new diesel engines, are included. The emissions from these sources are not considered for AQMD NSR purposes because a) the boilers are existing permitted sources not undergoing modification subject to NSR, b) the cooling towers are exempt from AQMD permitting requirements by Rule 219(d)(3) because they are not used for evaporative cooling of process water and do not cause an MICR greater than 1 in a million or a hazard index greater than 1.0, and c) the emergency engines are exempt from modeling by Rule 1304(a)(4) and 2005(k)(5).

Operation at 30F with duct burners on and evaporative cooling off results in the highest hourly emission rates for the turbines when in baseload (peak power) mode. The following table summarizes the maximum emission concentrations and corresponding emission factors on a heat input and fuel use basis.

TABLE 5 – Turbine Emissions With Duct Burners At 30°F And 60% RH

Pollutant	ppmvd @ 15% O ₂	lbs/MMbtu	lbs/MMscf
NO _x (prior to SCR)	9	0.0320	32.2
NO _x controlled 1 hour average	2.5	0.0089	8.94
SO _x	0.14	0.0071	7.14
CO controlled 1 hour average	6.0	0.0130	13.07
VOC	1.4	0.0017	1.71
PM ₁₀	----	0.0055	0.00175 gr/dscf

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Table 6 below shows hourly emission rates for baseload operation and also includes startup emissions. Note that hourly start-up emissions rates are higher than baseload emission rates for NOx and CO.

TABLE 6 – Turbine Hourly Emission Rates

Operating Scenario	Pollutant						
	NOx		CO		VOC	PM10	SOx
	lbs/hr ⁽¹⁾	lbs/hr ⁽²⁾	lbs/hr ⁽¹⁾	lbs/hr ⁽²⁾	lbs/hr	lbs/hr	lbs/hr
Baseload, 30°F, with Duct Burners	17.77	14.22	25.91	8.65	3.47	11.00	1.42
Hot Start	20.00	20.00	100	100	3.47	10.38	0.86
Warm Start	20.00	20.00	62.50	62.50	3.47	10.38	0.86
Cold Start	20.00	20.00	50	50	3.47	10.38	0.86

- (1) Short term average (i.e. use to calculate: NOx less than annual average, and CO less than 30-day average)
- (2) Long term average (i.e. use to calculate: NOx annual average, CO 30 day average)

Notes:

- NOx short term average is based on 2.5 ppm, long term average based on 2 ppm, includes duct burner operation.
- CO short term average based on 6 ppm, long term average based on 2 ppm.
- PM10 includes front and back halves
- Start-up emissions are based on engineering analysis of source test data from start-ups of similar turbines

1. Maximum Turbine Emissions

Maximum emissions are based on the emission factors from Table 6. Hourly emissions are based on start-ups for NOx and CO, while baseload emissions result in the highest hourly rate for PM10, VOC, and SOx. Daily maximums are based on an assumed 3 hour start (cold) for NOx, CO, and VOC emissions, along with 21 hours of baseload operation. For PM10, and SOx, 24 hours of baseload operation are used to generate the daily maximum.

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TABLE 7 – Maximum Turbine Emissions

Pollutant	Maximum Controlled Emissions Per Turbine	
	lbs/hr	lbs/day
NO _x	20	433.17
CO	100	694.11
VOC	3.47	83.28
PM ₁₀	11	264
SO _x	1.42	34.08

2. 30-Day Average Turbine Emissions for Non-RECLAIM Pollutants

Emission offsets are based on a 30-Day Average emission estimate. The following assumptions were made in determining 30-Day Average Emissions:

Each turbine will incur:

20 one hour hot starts (20 hours total),
4 two hour warm starts (8 hours total), and
1 three hour cold start per month (3 hours total).

for a total of 31 hours in start-up mode per turbine per month. The remaining hours in the month (689 hours) will be at baseload conditions, with duct burners on, and at 30°F. See Appendix I for sample calculations.

TABLE 8 - 30 Day Average Turbine Emissions and Required Offsets

Pollutant	30 Day Average Emissions (1 Turbine)	Offset Factor	Required Offsets (1 Turbine)	Total 4 Turbines Required Offsets
	lbs/day		lbs/day	lbs/day
CO	287.00	1.2	344	1,376
VOC	83.28	1.2	100	400
PM ₁₀ *	257.46	1.2	308	1,232
SO _x	34.08	1.2	41	164

* PM₁₀ emissions are based on a permit condition of 7,724 lbs/month per turbine as proposed by Mountainview.

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3. RECLAIM Annual Average NOx Emissions

Annual average NOx emissions are estimated for the purposes of determining the required RTCs for the 1st year of operation pursuant to Rule 2005. The annual NOx estimation assumes turbine operation 365 days per year, with 365 hours per year of start ups (233 hours hot starts, 96 hours warm starts, and 36 hours cold starts), and the remaining hours of operation (8,395) in baseload mode. The emissions estimate during baseload operation takes into consideration different ambient temperature, and whether or not the duct burners are fired, with the assumption that the duct burners will operate 2000 hours per year. Baseload operation is separated into 5 distinct operating scenarios as shown below. NOx is estimated using the SCR vendor guarantee of 1 ppm annual average outlet concentration. The facility will also need to account for the NOx emissions which will occur during the commissioning period. The emission estimate for NOx during this period is shown in Appendix C. The following table summarizes the calculations:

TABLE 9 – Annual Average NOx Emissions – 4 Turbines

Operating Mode	NOx Emissions		
	Annual Operation ⁽¹⁾	Hourly Emission Rate ⁽²⁾	Annual Emissions ⁽¹⁾
	hrs/yr	lbs/hr	lbs/yr
102F, w/DB	80	6.56	525
82F w/DB	3400	6.66	22,644
59F w/o DB	14420	6.38	92,000
30F w/o DB	11500	6.62	76,130
30F w/DB	4180	7.13	29,803
hot starts	932	20.00	18,640
warm starts	384	20.00	7,680
cold starts	144	20.00	2,880
Total 12 months			250,302
Average per month			20,858
Commissioning period (2 months)			69,284
Total 10 months plus commissioning			277,869

Notes:

(1) Total 4 turbines

(2) Based on 1 ppm annual average NOx concentration

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4. Emissions During Gas Turbine Commissioning Period

Gas turbine commissioning will consist of part load and full load tests performed on each pair of turbines for the purposes of “tuning in” the turbine combustors and the control systems. Once the commissioning period is completed for the 1st set of turbines, an identical commissioning period will begin for the 2nd set. Total time to complete each commissioning period is expected to be approximately 33 operating days. Emissions during commissioning will be higher than normal operation because the combustors will not be optimally tuned, and/or the SCR control system may not be operational. Reference Appendix C for the estimated emissions during commissioning. NOx emissions during commissioning will be reported for RECLAIM purposes using the lbs/mmcf emission factors as listed on the permit. There are 2 factors that apply during commissioning, a 64 lbs/mmcf factor which corresponds to 18 ppm for turbine testing when loads are above 60%, and a 356 lbs/mmcf factor corresponding to 100 ppm for turbine loads below 60%.

5. Ammonia Emissions

Ammonia emissions occur when some of the injected ammonia passes through the SCR catalyst unreacted. This is known as ammonia slip. The SCR catalyst vendor has provided a slip guarantee of 5 ppm maximum. Mass ammonia emissions are estimated in Appendix D, along with other toxic and/or carcinogenic air contaminants.

The 5 ppm ammonia slip limit represents free ammonia in the exhaust. Additionally, some ammonia will react with the sulfur in the exhaust to form ammonium sulfate. Ammonium sulfate exists the turbine exhaust as a gas, but upon cooling forms a solid particulate. The above emission estimates for particulates includes an assumed maximum 2 lbs/hr conversion of SOx and ammonia in the exhaust to particulate sulfate (approximately 75% conversion of available sulfur).

6. Cooling Tower Emissions

The cooling towers are exempt from permitting requirements by Rule 219(d)(3) because they are not used for evaporative cooling of process water. Furthermore, in accordance with the preamble of Rule 219, the cooling towers qualify from a permitting exemption because they do not cause an MICR greater than 1-in-a-million, nor do the acute or chronic hazard indices exceed 1.0. Therefore cooling tower emissions do not need to be offset, and were not included in the NSR modeling analysis (cooling tower emissions were included in the overall facility modeling analysis for AFC purposes). Estimates of cooling tower emissions are included in Appendix F.

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EVALUATION:

PART 1 SCAQMD REGULATIONS

RULE 212 – Standards for Approving Permits

The new gas turbines at Mountainview are considered a significant project under this rule due to the fact that the emissions exceed the daily maximums specified in subdivision (d). Therefore, public notice is required to be sent to all addresses within a _ mile radius of the project, a local newspaper publication, as well as those parties listed in subdivision (g) of the rule, including EPA Region IX, CARB, chief executives of both the city and county of San Bernardino, any comprehensive regional land use planning agency, and affected State and Federal Land Managers.

The required public notice period under this rule is 30 days.

Rule 218 – Continuous Emission Monitoring

The Mountainview facility will be required to install a CO CEMS to verify emissions of CO meet the hourly and daily emission limits. The CO CEMS will need to comply with the requirements of Rule 218, and the facility will need to submit a CEMS application for AQMD review and approval prior to installing the CEMS.

RULE 401 – Visible Emissions

Visible emissions are not expected under normal operating conditions of the turbines.

RULE 402 – Nuisance

Nuisance problems are not expected under normal operating conditions of the turbines.

RULE 407 – Liquid and Gaseous Air Contaminants

This rule limits the CO emissions to 2000 ppm max, and the sulfur content of the exhaust to 500 ppm for equipment not subject to the emission concentration limits of 431.1. Since the turbines are subject to the limits of Rule 431.1, only the 2000 ppm limit of this rule applies. It is expected that the equipment will be able to meet the CO limit with the use of an oxidation catalyst. Compliance will be verified through CEMS data.

RULE 409 – Combustion Contaminants

Limits PM emissions to 0.1 gr/scf. The equipment is expected to meet this limit based on the calculations shown below:

Estimated exhaust gas 60 mmscf/hr

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$$\begin{aligned}
 \text{Grain loading} &= \frac{11 \text{ lbs/hr (7000 gr/lb)}}{60 \text{ E+06 scf/hr}} \\
 &= 0.00128 \text{ gr/scf}
 \end{aligned}$$

Compliance will be verified through the initial performance test as well as periodic testing as required by Title V.

RULE 431.1 – Sulfur Content of Natural Gas

The rule requires that gas fired equipment meet a sulfur content limit of 40 ppm on a 4 hour averaging time. Commercial grade natural gas to be burned in the turbines is expected to meet this limit.

RULE 475 –Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meet a limit for combustion contaminants (combustion contaminants are defined as particulate matter in AQMD Regulation I) of 11 lbs/hr or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met. Mass PM10 emissions from the Mountainview turbines are estimated at 11 lbs/hr. However, on a concentration basis estimated grain loading is 0.00128 gr/scf (see calculations under Rule 409 discussion). Therefore, compliance is expected. Compliance will be verified through the initial performance test as well as periodic testing required by Title V.

REGULATION XIII – New Source Review

The Mountainview project is subject to the offsets, modeling, and BACT requirements of New Source Review. Following is a discussion of each requirement.

1. Offsets

Offsets for Non-RECLAIM pollutants are based on a calendar monthly average in accordance with Rule 1306(b). Required offsets are shown in Table 8 above.

Mountainview has purchased the following offsets for this project:

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A. CO ERCs

ERC Certificate Number	Company	City	Quantity
AQ001463	Alumax Mill Products, Inc	Riverside	56
AQ001404	Central Plants	LA	13
AQ002080	Central Plants	Santa Fe Springs	671
AQ002370 and 2372	Rhodia Indc	Carson	30
AQ000979	GWF Power Systems Co.	Newhall	26
AQ002768 and 2815	National Offsets	Vernon	11
AQ001481	Granite Construction Co.	Indio	340
AQ001782	Unocal Corp	Brea	232
Total Purchased			1379
Total Required			1376

C. SO_x ERCs

ERC Certificate Number	Company	City	Quantity
AQ002238	Signal Hill Holding Corp	Carson	47
AQ000349	GAF Building Materials	Irwindale	114
AQ003046	GAF Building Materials	Irwindale	48
AQ001121	California Steel Industries	Fontana	50
AQ000563	Miller Brewing	Irwindale	378
AQ000542	California Amforge	Azusa	17
AQ001377	Alcoa	Vernon	88
AQ000333	Technicolor	North Hollywood	4
AQ000668	Hughes Aircraft Co.	El Segundo	9
Total Purchased			755
Total Required			164

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B. PM10 ERCs

ERC Certificate Number	Company	City	Quantity
AQ000765	March AFB	South Gate	10
AQ002594	Internat'l Light Metals/Lockhead	LA	262
AQ002627	Equilon Enterprises	Carson	100
AQ001545	Owens Brockway Glass	Pomona	60
AQ002523	Alumax	Riverside	96
AQ002371	Rhodia Inc	South Gate	3
AQ000545	So Cal Gas	Monterey Park	6
AQ002709	Equilon Enterprises	Carson	165
AQ000669	Hughes Aircraft	El Segundo	25
AQ000011	Firma Inc	South Gate	12
AQ001909	Kiewit-Granite	Hemet	1
AQ002097	Kiewit-Granite	Hemet	26
AQ001910	Kiewit-Granite	Hemet	5
AQ002054 and 2256	Kiewit-Granite	Hemet	32
AQ002506	NI Industries	Vernon	4
AQ000376	GE-Energy & Env. Research	Santa Ana	7
AQ002828	National Offsets		3
AQ000615	Deluxe Laboratories, Inc	Hollywood	11
A/N 364007*	Atkinson, Washington, Zackery	Winchester	105
AQ000350	GAF Building Products	Irwindale	4
AQ000149	Rhodia Inc	LA	1
AQ000232	Benjamin Moore	Commerce	4
Total Purchased			942
Total Converted from SOx			295
Total Available			1237
Total Required			1232

* recently approved, no ERC certificate number at this time.

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D. VOC ERCs

ERC Certificate Number	Company	City	Quantity
AQ002700	Crown Beverage Packaging	Van Nuys	121
AQ002705	Alumax Mill Products	Riverside	201
AQ001405	Central Plants	LA	13
AQ001447	Central Plants	Santa Fe Springs	207
Total Purchased			542
Total Required			400

Sufficient offsets for VOC, CO, and SO_x have been purchased by the applicant. However, PM₁₀ credits to completely offsets project emissions were not available for purchase. Mountainview has proposed an interpollutant offset of SO_x for PM₁₀. The interpollutant offset has been reviewed and approved by AQMD planning staff at a ratio of 2.0 to 1. Therefore, the excess 591 lbs of SO_x credits are converted to 294 lbs of PM₁₀. When added to the 942 lbs of purchased PM₁₀, total credits available for offsetting are 1236 lbs/day, sufficient to cover project emissions.

2. Modeling

Modeling is required for CO and PM₁₀ emissions per Rule 1303(b). Rule 1303 requires that through modeling, the applicant must substantiate that the project does not exceed the most stringent ambient air quality standard nor a significant change in air quality concentration. Maximum project impacts of CO and PM₁₀ emissions were determined using the ISCST3 model. Table 10 below shows the applicable standards for the subject pollutants, and the results from Mountainview modeling analysis.

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TABLE 10 - New Source Review Modeling

Pollutant	Averaging Time	Most Stringent Air Quality Standard	Mountainview Model Results	Significant Change in Air Quality Concentration	Mountainview Model Results
CO	1-hour	23 mg/m ³	9.2 ^(a) mg/m ³	1.1 mg/m ³	34.1 ^(a) ug/m ³
	8-hour	10 mg/m ³	6.9 ^(a) mg/m ³	0.5 mg/m ³	11.1 ^(b) ug/m ³
PM10	24-hour	50 ug/m ³	146 ^(a) ug/m ³	2.5 ug/m ³	1.56 ^(b) ug/m ³
	Annual Geometric Mean	30 ug/m ³	48 ^(a) ug/m ³	1 ug/m ³	0.60 ^(b) ug/m ³

- a Includes entire facility, Units 1-4, cooling towers, and diesel engines (accounts for net emission increase for Units 1 and 2 boilers and cooling towers)
- b Includes all 4 gas turbines

The model was reviewed by AQMD modeling staff and deemed acceptable (refer to memo from Henry Hogo to Pang Mueller dated 10/5/00, included as an attachment to this evaluation). Reference Appendix B for a more thorough discussion.

3. BACT

BACT is defined in AQMD Rule 1301 as follows:

BACT means the most stringent emission limitation or control technique which:

- (1) has been achieved in practice for such category or class of source; or
- (2) is contained in any State Implementation Plan (SIP) approved by the US EPA for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitations or control technique is not presently achievable; or
- (3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.

This definition of BACT is consistent with the federal LAER definition.

The California Air Resource Board published a document entitled Guidance for Power Plant Citing and Best Available Control Technology, dated September 1999. In it, they summarize required BACT for cogeneration power plants as follows:

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TABLE 11 – Required BACT

NO _x	CO	VOC	PM ₁₀	SO _x
2.5 ppmvd @ 15% O ₂ , 1 hour rolling average OR 2.0 ppmvd @ 15% O ₂ , 3 hour rolling average	6 ppmvd @ 15% O ₂ , 3 hour rolling average	2 ppmvd @ 15% O ₂ , 1 hour rolling average OR 0.0027 lbs/MMbtu, HHV	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O ₂)

Source: CARB, *Guidance for Power Plant Citing and Best Available Control Technology*, dated September 1999.

Mountainview Power is proposing the following BACT levels for this project. Note that these levels generally represent guaranteed emissions under baseload operating conditions.

TABLE 12 – Mountainview Power Proposed BACT

NO _x	CO	VOC	PM ₁₀	SO _x
2.5 ppmvd @ 15% O ₂ , 1 hour rolling average	6 ppmvd @ 15% O ₂ , 1 hour rolling average	1.4 ppmvd @ 15% O ₂ , 1 hour rolling average	Exclusive use of natural gas fuel with expected sulfur content of 0.25 grain/100 scf (corresponds to an emission factor of 0.006 lbs/MMbtu or 11 lbs/hr)	Exclusive use of natural gas fuel with expected sulfur content of 0.25 grain/100 scf (corresponds to an emission factor of 0.00071 lbs/MMbtu or 1.31 lbs/hr)

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The proposed control levels meet BACT requirements for all criteria pollutants. See discussion under Rule 2005 for more detailed analysis of BACT for NO_x.

Ammonia Emissions

Rule 1303(a)(1) requires the use of BACT for ammonia emissions. The 1999 CARB BACT guidance recommends ammonia BACT levels for large gas turbines set at not more than 5 ppm. Mountainview is proposing to meet a 5 ppm ammonia slip limit, and has deemed a lower slip limit infeasible for this project based on the following analysis:

Mountainview has chosen to use an ammonia based control system to reduce NO_x emissions to required BACT levels. Zero ammonia slip levels cannot be achieved with an SCR control system. Therefore, ammonia slip levels must meet BACT requirements as determined through a search of “achieved in practice” projects.

The states of Massachusetts and Rhode Island have established ammonia slip LAER levels of 2 ppmvd. These slip levels have been proposed in conjunction with NO_x levels in the range of 2.0 – 3.5 ppm, depending on operating mode. For example, the Site Energy Mystic Facility was approved by the Massachusetts Department of Environmental Protection to meet a NO_x 1 hour average of 2 ppm, along with an ammonia slip level of 2 ppm, 1 hour average. However, because the turbine has not yet been installed or operated, these NO_x and ammonia slip levels are not considered achieved in practice and are not used in the BACT determination for the Mountainview project.

Mountainview is proposing a 2.5 ppm NO_x 1 hour limit, along with a goal of achieving an annual average limit of 1.0 ppm in conjunction with the proposed ammonia slip level of 5 ppm.

SCONO_x is a proprietary control technology developed by Goaline Environmental which can achieve NO_x levels of 2.5 ppm with zero ammonia slip. However, this technology was not chosen for the Mountainview project based on the results of the “top-down” BACT analysis done for NO_x emissions (see discussion under Rule 2005 evaluation).

In conclusion, the 5 ppm ammonia slip level is deemed as meeting the BACT requirements for this project based on the 1999 CARB BACT guidance document.

RULE 1401 – Carcinogenic Air Contaminants

Mountainview ran a Tier 4 modeling analysis using ISCST3 to determine maximum cancer risks. They also evaluated acute and chronic risks from emissions of toxic air contaminants using the ARB/OEHHA Health Risk Assessment Program.

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Results show that the MICR is 0.17 in a million, which is below the Rule 1401 threshold limits of 1 in a million and 10 in a million. Highest cancer impact receptor is approximately 19 km northwest of the facility. Calculated Acute Hazard Index was 0.4, less than the rule limit of 1.0. Additionally, the Chronic Hazard Index was 0.09, also less than the rule limit of 1.0. Cancer risk and hazard index analysis included carcinogenic emissions from all four cooling towers, existing boilers 1 and 2, the new gas turbines, and the new diesel engines.

The model was reviewed by AQMD modeling staff and deemed acceptable. Below is a summary of results:

TABLE 13 – Results of Health Risk Assessment

MICR	Acute Hazard Index	Chronic Hazard Index
0.17	0.4	0.09

RULE 1404 – Hexavalent Chromium for Cooling Towers

Hexavalent chromium-containing water treatment chemicals will not be used in either the new or existing cooling towers. Therefore, a plan is not required under this rule.

REGULATION XVII – Prevention of Significant Deterioration

The South Coast Basin where the project is to be located is in attainment for NO₂ and SO₂ emissions. Therefore a PSD analysis for these pollutants must be conducted.

Rule 1702 defines a significant emission increase of NO₂ or SO₂ as an increase greater than 40 tpy. The turbine project will result in a 238 tpy increase in NO_x and a 23 tpy increase in SO₂ (includes emissions from the turbines/duct burners and the diesel engines). The addition of the gas turbines/diesel engines is therefore considered a significant increase for NO₂ only, and is subject to PSD review for this pollutant. The boiler emissions are not included in the PSD analysis because the installation of the water injection system results in an emissions reduction, and is exempt from PSD (see memo from District Council Barbara Baird dated 3/8/2000).

Requirements for a significant emission increase under Rule 1703 include the following:

- Use of BACT [1703(a)(3)(B)]
- Modeling to determine impacts of the project of National and State AAQS and increases over the baseline concentration [1703(a)(3)(C)]

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- Analysis of ambient air quality in the impact area [1703(a)(3)(D)]
- Analysis of project impacts on visibility, soil, and vegetation [1703(a)(3)(E)]

Affected Federal Land Managers have the opportunity to review and comment on the proposed project. The CEC has provided the Park Service and Forest Service with copies of the analysis (approximately March-April 2000).

The following methodology was used in performing the PSD analysis:

1. Determine whether preconstruction monitoring is required
2. Assessment of significance under PSD
3. Determine Ambient Air Quality Impacts
4. Determine Impacts in Class I Areas

Mountainview determined that the maximum modeled impacts from the project were 0.53 ug/m^3 on an annual basis. Since this does not exceed the preconstruction monitoring threshold of 14 ug/m^3 , preconstruction monitoring is not required, and monitoring data from nearby monitoring stations can be used to determine ambient conditions.

The modeled impact of 0.53 ug/m^3 was also compared to the PSD significance threshold of 1.0 ug/m^3 . Since the project does not exceed the significance threshold, an increment consumption analysis is not required.

The ambient air quality impacts analysis was conducted under NSR. Refer to that section for a discussion of the results.

Finally, the impacts on Class I areas were analyzed. The Class I areas within 100 km of the project are as follows:

Aqua Tibia Wilderness Area (68km)
Cucamonga Wilderness Area (34km)
Joshua Tree National Park (73km)
San Gabriel Wilderness Area (60km)
San Gorgonio Wilderness Area (27km)
San Jacinto Wilderness Area (48km)

Impacts of NO₂, SO₂, and PM₁₀ on these areas were modeled. The results as summarized in the table below show that maximum impacts are below the PSD Class I Increment for all pollutants in all areas.

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TABLE 14 – Criteria Pollutant Impacts in Class I Areas

Pollutant	PSD Class I Increment	Aqua Tibia	Cucamonga	Joshua Tree	San Gabriel	San Gorgonio	San Jacinto
	ug/m3	ug/m3	ug/m3	ug/m3	ug/m3	ug/m3	ug/m3
NO2 Annual	2.5	0.002	0.001	0.019	0.045	0.015	0.006
SO2 Annual	2	0.000	0.000	0.003	0.006	0.002	0.000
24-Hour	5	0.007	0.004	0.018	0.021	0.013	0.006
3-Hour	2.5	0.059	0.029	0.084	0.037	0.039	0.017
PM10 Annual	5	0.002	0.003	0.026	0.058	0.022	0.009
24-Hour	10	0.060	0.046	0.165	0.182	0.128	0.055

A visibility analysis was also conducted for all Class I areas, Table 14 shows the results from the visibility analysis:

TABLE 15 – Visibility Impacts on Class I Areas

Class I Area	Percent Change in Extinction	Acceptable Change
Aqua Tibia WA	1.36%	5%
Cucamonga WA	0.81%	5%
Joshua Tree NP	4.92%	5%
San Gabriel WA	4.47%	5%
San Gorgonio WA	3.42%	5%
San Jacinto WA	1.13%	5%

All visibility impacts are below the acceptable change limits.

AQMD modeling staff has reviewed the modeling and determined the analysis was conducted appropriately (see memo from Henry Hogo to Pang Mueller dated 10/5/00)

Rule 2005 – NSR for Reclaim

Rule 2005 applies to the NOx emissions from the turbines. The rule requires new sources to provide RTCs, perform a modeling analysis, and provide BACT. Each of these requirements are discussed in further detail below.

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1. RTCs

Rule 2005(b)(2)(A) requires that a new facility provide sufficient RTCs to offset emissions prior to the first year of operation on a 1-to-1 basis. Furthermore, paragraph (b)(2)(B) states that the RTCs must comply with the zone requirements of Rule 2005(e). The Mountainview Power Plant is expected to begin operation in March 2003, and since the facility is located in Zone 2, RTCs may be obtained from either Zone 1 or Zone 2. The following RTCs have been secured by the facility thus far for Cycle 2-2002, Cycle 1-2003, Cycle 2-2003, and Cycle 1-2004, all of which may be applied to operation of the facility from March 2003 to March 2004:

Compliance Year	Quantity Purchased
	lbs
7/02-6/03	4600
1/03-12/03	81996
7/03-6/04	122770
1/04-12/04	85322
Total Purchased	294,688
Total Required	277,869

The acquired RTCs are sufficient to cover estimated NOx emissions as summarized in Table 9.

2. Modeling

Modeling is required for NOx emissions per Rule 2005(c)(1)(B). Rule 2005 requires that through modeling, the applicant substantiate that the project does not exceed the most stringent ambient air quality standard nor a significant change in air quality concentration. Maximum project impacts of NOx emissions were determined using the SCREEN3 model for 1 hour impacts, and ISCST3 model for the annual standard. Table 16 below shows the applicable standards and the results from Mountainview modeling analysis. As discussed in Appendix B, model inputs for NO2 assumed a 2.0 ppm NOx concentration for the estimate of long-term (i.e. annual) impacts. Maximum one-hour impacts assumed 2 turbines in start-up mode and 2 turbines in baseload operation (equivalent to 75.15 lbs/hr for 4 turbines).

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TABLE 16 - New Source Review NO_x Modeling

Pollutant	Averaging Time	Most Stringent Air Quality Standard	Mountainview Model Results ^(a)	Significant Change in Air Quality Concentration	Mountainview Model Results ^(b)
NO ₂	1-hour	500 ug/m ³	365 ug/m ³	20 ug/m ³	13.9 ug/m ³
	Annual	100 mg/m ³	72 ug/m ³	1 ug/m ³	0.52 ug/m ³

(a) Includes entire facility, units 1-4 and diesel engines

(b) Includes gas turbines only

Modeling analysis for plume visibility is also required by Rule 2005 (and Rule 1303). The only Class I area within the prescribed distance of the rule is San Geronio, therefore the analysis is limited to this area only. A Level-2 analysis was performed using actual meteorological data from the Redlands data set. Results of the analysis show that impacts will not exceed the allowable change of 2.0 percent total color contrast or the plume contrast level of 0.05.

3. BACT

For the Mountainview project, a “top-down” BACT analysis was performed consistent with guidance provided in EPA’s October 1990 Draft New Source Review Workshop Manual. There are 5 basic steps to the top down approach:

1. Identify all control techniques
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate most effective controls and document results
5. Select BACT

For the Mountainview turbines the following potential control techniques were identified:

Water/Steam Injection

Dry Low-NO_x combustor design (DLN)

Catalytic combustors (i.e. XONON)

Selective non-catalytic reduction (i.e. ammonia or urea injection)

Non-selective catalytic reduction (i.e. 3-way catalyst)

SCR

SCONox

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Infeasible Options

Catalytic combustors

The XONON combustors have been commercially demonstrated in a 1.5 MW natural gas fired turbine in California, and commercial availability of the technology in a 200 MW GE Frame 7G was recently announced. However, GE has indicated that the use of XONON technology is not commercially available for the Mountainview project. No other turbine vendor has indicated the commercial availability of catalytic combustion systems. Therefore, it was determined that catalytic combustion controls are not technologically feasible for this project because of the lack of commercial availability.

Selective non-catalytic reduction

SNCR involves the injection of ammonia or urea directly into the exhaust gases without use of a catalyst. This technology requires exhaust temperatures in the range of 1200° to 2000°F and is mainly associated with boiler or heater NOx control. The exhaust gas temperature for the Mountainview turbines will be in the range of 1087° to 1200°F, generally below the required temperature for effect use of this technique.

Non-selective catalytic reduction

This technique uses a catalyst without injected reagents, and is mainly associated with automobile exhaust and rich-burn stationary IC engines. NSCR is only effective in a stoichiometric or fuel rich environment when combustion gas is nearly deplete of oxygen. Typical oxygen concentration in turbine exhaust is 14 to 16 percent. Therefore, NSCR is not technologically feasible for the Mountainview turbines.

Remaining Technologies

After elimination of the above technologies, the following control types remain:

Water/Steam Injection

Dry Low-NOx combustor design (DLN)

SCR

SCONox

Mountainview determined that DLN combustors were preferable to water or steam injection due to the superior emission control performance, additional CO and VOC benefits, and increased efficiency of the DLN technology. Mountainview will utilize DLN combustors for this project.

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SCR and SCONOx

Both SCR and SCONOx are available and technologically feasible for NOx control of the Mountainview turbines. SCONOx has been demonstrated on a 22 MW turbine at the Sunlaw facility in Vernon, CA. Based on operating data from this turbine, SCONOx can achieve a NOx level of 2.5 ppm based on a 1 hour average. SCR is also capable of achieving NOx levels of 2.5 ppm on a 1 hour basis, therefore the technologies are generally equivalent in NOx control efficiency, and BACT would be achieved with the use of either system.

Mountainview Power has chosen to use an SCR control system in conjunction with DLN combustors for NOx control for the turbines. The turbine emissions will meet a 2.5 ppm NOx level on a 1 hour basis, this level is deemed to meet the BACT requirements for this project. Furthermore, the facility expects to achieve 1.0 ppm NOx on an annual average basis. Although the 1.0 ppm NOx will not be a specific permit limit, the facility will be limited to a mass NOx equivalent to their estimated 1st year RTC requirements, which are based on 1.0 ppm.

4. Additional Requirements for Major Sources

Rule 2005 requires that a major source also comply with the following:

1. Certify that all major sources in the state under control of the applicant are in compliance with all applicable federal emissions standards.
2. Submit an analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed source.
3. Conduct a visibility analysis.

Mountainview has 1) certified on the 400-A form that all major sources under their control in the state comply with federal regulations, 2) done an alternative analysis under the AFC process, and 3) conducted a visibility analysis under NSR and PSD. Therefore, the above 3 requirements have been met.

Rule 2012 – Monitoring Recording and Record Keeping for RECLAIM

The Mountainview facility is currently in compliance with all monitoring, record-keeping, and reporting requirements of Reclaim for the existing facility. The new turbines will be classified as major sources for RECLAIM purposes. As such each turbine will be required to have a NOx CEMS and a fuel meter, and emissions must be reported through an RTU on a daily basis. Mountainview has 12 months from the date of installation of the turbines to install the required monitor and have them certified. The facility must submit

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a CEMS application and plan for AQMD review and approval prior to receiving final certification on the CEMS.

Regulation XXX – Title V

The Mountainview facility is currently subject to the Title V requirements. The final “initial” Title V permit was issued in August, 1999. The addition of the new turbines is considered a Significant Permit Revision as defined in Rule 3000.

PART 2 STATE REGULATIONS

California Environmental Quality Act (CEQA)

The combined cycle facility requires certification by the California Energy Commission (CEC). The requirements of a CEQA analysis are met under the CEC licensing procedure.

PART 3 FEDERAL REGULATIONS

40CFR Part 60 Subpart GG – NSPS for Gas Turbines

NSPS applies to the Mountainview turbines since the heat input is greater than 10.7 gigajoules per hour at peak load. Actual unit rating is $1991(10^6)$ btu/hr X 1055 joules/btu = 2100 gigajoules/hr. The standards which will be applied to the turbine are as follows (see Appendix H for the calculations):

NO_x = 87.9ppm
SO_x = 150ppm

A performance test is required within 60 days of installation. Compliance is expected.

40CFR Part 63 – NESHAPS

EPA is in the process of establishing a NESHAPS for gas turbines, a draft rule is expected in November 2000, with promulgation in 2002. Until the NESHAPS is promulgated, turbine MACT standards must be evaluated on a case-by-case basis. In this case, because HAP emissions for the Mountainview turbines are below the major source thresholds of 10 tpy for a single HAP or 25 tpy for a combination of HAPs, the turbines are not considered major sources of HAP, and are exempt from this regulation.

40CFR Part 64 - Compliance Assurance Monitoring

The CAM regulation applies to major stationary sources which use control equipment to achieve a specified emission limit. The rule is intended to provide “reasonable assurance” that the control systems are operating properly to maintain compliance with the emission

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limits. The turbines are major sources for NO_x, CO, and VOC emissions, and will be subject to a BACT limit for each of these pollutants. Control equipment in the form of an SCR will be used to comply with the NO_x limit, while an oxidation catalyst will be used to meet the CO limit. The VOC BACT limit will be met through the use of natural gas fuel and efficient combustion design. Therefore, the CAM rule applies to NO_x and CO emissions, however, there is no add-on control equipment used to meet the VOC limit, and CAM would not apply for this pollutant.

Compliance with the BACT limits for NO_x and CO will be based on CEMS, and the exemption of 64.2(b)(vi) (continuous compliance determination method) therefore applies.

Additionally, the NO_x RECLAIM cap is exempt from CAM by 64.2(b)(iv) (emission trading programs).

40CFR Part 72 – Acid Rain Program

The existing boilers at the Mountainview facility are currently subject the requirements of the Federal Acid Rain program. The acid rain program is similar to RECLAIM in that facilities are required to cover SO₂ emissions with “SO₂ Allowances” (similar to RTCs), or purchases of SO₂ on the open market. The plant is also required to monitor SO₂ emissions through use of fuel gas meters and gas constituent analysis (use of emission factors is also acceptable in certain cases) or with the use of exhaust gas CEMS. It is expected that Mountainview will comply with the monitoring requirements of the acid rain provisions with the use of gas meters in conjunction with gas analysis.

RECOMMENDATION:

The proposed Mountainview project meets all AQMD, State, and Federal Rules and Regulations. It is recommended that a Permit to Construct be issued after completion of the notice period, considering any comments received, and upon final certification of the CEQA document.

The following permit conditions shall apply to insure the turbines operate in compliance with all applicable standards.

Note that the annual fuel consumption limit along with the annual mass limit on NO_x (condition 1-1) is set to insure compliance with the assumptions made in determining the amount of RTCs required to cover the 1st year of operation (namely, the 1.0 ppm annual average NO_x concentration). The fuel limit is based on 50% of the heat input assumed by Mountainview in their calculation of the 1st year NO_x emissions at 1.0 ppm. This limit will restrict the operation of the Mountainview plant in the 1st year in the event that actual

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annual NO_x emissions are as high as 2.0 ppm (the limit contained in condition 99-2). The limit is derived by dividing the 1st year estimated RTC amount of 250,267 lbs/yr by the emission factor of 7.2 lbs/mmcf corresponding to a NO_x concentration of 2.0 ppm.

The 2.0 ppm annual average NO_x limit in condition 99-2 is set to insure compliance with the assumptions used in the dispersion modeling.

CONDITIONS:

Gas Turbines/SCRS

- 1-1 The operator shall limit the fuel use to no more than 35,000 mmcf/yr.

The purpose of this condition is to insure the facility does not exceed the 1st year RTCs provided for the project. This condition shall apply during the 1st 12 months of operation, commencing with the initial operation of the first gas turbine (Devices D18, D27, D36, or D45). This condition shall not apply if the operator demonstrates to the satisfaction of the AQMD that the total NO_x emissions from units D18, D27, D36, and D45 do not exceed 250,267 pounds during this period.

This limit shall be based on the total combined limit for equipment turbines 3-1, 3-2, 4-3, and 4-4, devices D18, D27, D36, and D45.

[Rule 2005]

- 12-1 The operator shall install and maintain a continuous monitoring system to accurately indicate the ammonia injection rate of the ammonia injection system.

The operator shall also install and maintain a device to continuously record the parameter being measured.

[Rule 1303 – BACT]

- 12-2 The operator shall install and maintain a temperature gauge to accurately indicate the temperature in the SCR catalyst.

The operator shall also install and maintain a device to continuously record the parameter being measured.

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28-1 The operator shall conduct a source test in accordance with the following specifications:

The test shall be conducted within 60 days of the approval of the source test protocol, but no later than 180 days after initial start up of the turbines.

The test shall be conducted to determine the NO_x emissions using District method 100.1 measured over a 1 hour averaging time period.

The test shall be conducted to determine the CO emissions using District method 100.1 measured over a 1 hour averaging time period.

The test shall be conducted to determine the SO_x emissions using District method 100.1 measured over a 1 hour averaging time period.

The test shall be conducted to determine the ROG emissions using a District approved method measured over a 1 hour averaging time period.

The test shall be conducted to determine the PM emissions using a District approved method measured over a 1 hour averaging time period.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the test shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output (MW).

The test shall be conducted to determine the NH₃ emissions using District approved method measured over a 1 hour averaging time period.

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the engineer identified on the P/C no later than 45 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the test, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of R304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at loads of 100%, 75%, and 50% of maximum load.

The District shall be notified of the date and time of the test at least 10 days prior to the test.

[Rule 1303 – Offsets, Rule 1303 – BACT, Rule 2005]

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28-2 The operator shall conduct a source test in accordance with the following specifications:

The test shall be conducted quarterly.

The test shall be conducted to determine the NH₃ emissions using a District approved method measured over a 1 hour averaging time period.

The District shall be notified of the date and time at least 7 days prior to the test.

The test shall be conducted and the results submitted to the District within 45 days after the test date.

[Rule 1303 – BACT]

40-1 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 15 percent oxygen, dry basis.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute.

All moisture concentration shall be expressed in terms of % corrected to 15%.

Emission data shall be expressed in terms of mass rate (lbs/hr). In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

Emission data shall be expressed in terms of lbs/mmcf.

Source test results shall also include turbine fuel flow rate under which the test was conducted.

Source test results shall also include turbine and generator output under which the test was conducted.

[Rule 1303 – Offsets, Rule 1303 – BACT, Rule 2005]

57-1 The operator shall vent this equipment to the SCR control whenever the turbines are in operation. The turbines shall not begin start-up (defined as including the purge cycle) until the SCR catalyst has been preheated to a temperature of at least 500°F. This condition shall not apply during the turbine commissioning period.

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[Rule 2005]

63-1 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
CO	8,610 LBS IN ANY 1 MONTH
VOC	2,498 LBS IN ANY 1 MONTH
PM10	7,725 LBS IN ANY 1 MONTH
SOx	1,005 LBS IN ANY 1 MONTH

For the purposes of this condition, the operator shall calculate monthly emissions by using monthly fuel use data, and the following emission factors: VOC, 1.64 lbs/mmscf, PM10, 5.21 lbs/mmscf, and SOx, 0.67 lbs/mmscf.

Compliance with the CO emission limit shall be verified through CEMS data.

[Rule 1303 – Offsets]

67-1 The operator shall keep records, in a manner approved by the District, for the following parameters or items:

Fuel use during the commissioning period. The fuel use data shall be used to determine the number of operating days and the percent load on the turbines.

[Rule 2012]

82-1 The operator shall maintain a CEMS to measure the following parameters:

CO concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis

The CEMS will convert the actual CO concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

The CEMS shall be installed operated in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD.

The CEMS shall be installed and operated to measure CO concentration over a 15 minute averaging time period.

[Rule 1303 – BACT]

82-2 The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppm

The CEMS shall be installed and operating no later than 12 months after the initial start-up of the turbine. During the interim period between the initial

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start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within 2 weeks of the turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up.

[Rule 2012]

- 99-1 The 2.5 ppm NO_x emission limit shall not apply during startup or during the commissioning period. Startup time shall not exceed 3 hours per day. The commissioning period shall not exceed 33 operating days from the date of initial start-up. The operator shall provide the AQMD with written notification of the start-up date. No more than 2 turbines shall be in start-up mode at any one time. No more than 2 turbines shall be commissioned at any one time.

[Rule 2005]

- 99-2 The 2 ppm NO_x emission limit shall not apply during startup or during the commissioning period. Startup time shall not exceed 3 hours per day. The commissioning period shall not exceed 33 operating days from the date of initial start-up. The operator shall provide the AQMD with written notification of the initial start-up date. The 2 ppm limit is set to insure compliance with the assumptions made in dispersion modeling. No more than 2 turbines shall be in start-up mode at any one time. No more than 2 turbines shall be commissioned at any one time.

[Rule 2005]

- 99-3 The 6 ppm CO emission limit shall not apply during startup or during the commissioning period. Startup time shall not exceed 3 hours per day. The commissioning period shall not exceed 33 operating days from the date of initial start-up. The operator shall provide the AQMD with written notification of the initial start-up date. No more than 2 turbines shall be in start-up mode at any one time. No more than 2 turbines shall be commissioned at any one time.

[Rule 1303 – BACT]

- 99-4 The 64 lbs/mmcsf NO_x emission limit shall only apply during the turbine commissioning period when the turbine is operating above 60% load to report RECLAIM emissions.

[Rule 2012]

- 99-5 The 32 lbs/mmcsf NO_x emission limit shall only apply during the interim reporting period to report RECLAIM emissions and shall not include the turbine commissioning period. The interim reporting period shall not exceed 12 months from the initial start-up date.

[Rule 2012]

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99-6 The 356 lbs/mmcsf NOx emission limit shall only apply during the turbine commissioning period when the turbine is operating below 60% load to report RECLAIM emissions.

[Rule 2012]

99-7 The 75.15 lbs/hr NOx emission limit shall only apply during turbine start-ups. For the purposes of this condition, the limit shall be based on the total combined emissions from the 4 turbines 3-1, 3-2, 4-3, and 4-4, devices D18, D27, D36, and D45. Start-up shall not exceed 3 hours per day.

[Rule 2005]

179-1 For the purpose of the following condition numbers, continuous monitoring shall be defined as measuring at least once every 15 minutes, except as allowed by Rule 2000.

Condition number 12-1

{Rule 1303 – BACT}

179-2 For the purpose of the following condition numbers, continuous recording shall be defined as recording at least once every hour.

Condition number 12-1

[Rule 1303 – BACT]

195-1 The 2.5 ppm NOx emission limit is based on a 1 hour average, at 15 percent oxygen, dry.

[Rule 2005]

195-2 The 6 ppm CO emission limit is based on a 1 hour average, at 15 percent oxygen, dry.

[Rule 1303 – BACT]

195-3 The 5 ppm NH3 emission limit is based on a 1 hour average, at 15 percent oxygen, dry.

[Rule 1303 – BACT]

195-4 The 2 ppm NOx emission limit is based on an annual average, at 15 percent oxygen, dry.

[Rule 2005]

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327-1 For the purposes of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.

[Rule 475]

372-1 The operator shall determine compliance with the particulate matter (PM) emission limit by conducting a source test at the outlet of the exhaust stack annually using AQMD Method 5.1. Each test shall include:

(a) One test using natural gas operating at minimum load under normal operating conditions, if natural gas is burned more than 120 consecutive hours or 200 hours accumulated over any 12 consecutive months. The test shall be conducted no later than 6 months after the time limit has been exceeded;

(b) One test using natural gas operating at maximum load under normal operating conditions, if natural gas is burned more than 120 consecutive hours or 200 hours accumulated over any 12 consecutive months. The test shall be conducted no later than 6 months after the time limit has been exceeded;

The annual source test frequency will be reduced to at least once every 5 years under the highest emitting load if three consecutive annual tests show compliance with either the concentration limit or the mass emission limit.

No test shall be required in any one year for which the equipment is not in operation.

[Rule 3004 – Periodic Monitoring]

Diesel Emergency Generator

F14-1 The operator shall not use fuel oil containing sulfur compounds in excess of 0.05 percent by weight.

[Rule 431.2]

1-1 The operator shall limit the operating time to no more than 200 hours per year.

[Rule 1110.2, Rule 1304-Exemptions, Rule 1401]

12-3 The operator shall install and maintain a non-resettable elapsed time meter to accurately indicate the elapsed operating time of the engine.

[Rule 1110.2, Rule 1304-Exemptions, Rule 1401]

67-2 The operator shall keep records, in a manner approved by the District, for the following parameters or items:

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date of operation, the elapsed time, in hours, and the reason for operation.

Records shall be kept and maintained on file for a minimum of two years and made available to district personnel upon request

[Rule 1110.2, Rule 1304-Exemptions, Rule 1401]

162-1 The operator shall use this equipment only during utility failure periods, except for maintenance purposes.

[Rule 1110.2, Rule 1304-Exemptions, Rule 1401]

177-1 The operator shall set and maintain the fuel injection timing of the engine at 4 degrees retarded relative to standard timing.

[Rule 1303-BACT]

Diesel Fire Pump Engine

F14-1 The operator shall not use fuel oil containing sulfur compounds in excess of 0.05 percent by weight.

[Rule 431.2]

1-1 The operator shall limit the operating time to no more than 200 hours per year.

[Rule 1110.2, Rule 1304-Exemptions, Rule 1401]

12-3 The operator shall install and maintain a non-resettable elapsed time meter to accurately indicate the elapsed operating time of the engine.

[Rule 1110.2, Rule 1304-Exemptions, Rule 1401]

67-1 The operator shall keep records, in a manner approved by the District, for the following parameters or items:

date of operation, the elapsed time, in hours, and the reason for operation. Records shall be kept and maintained on file for a minimum of two years and made available to district personnel upon request

[Rule 1110.2, Rule 1304-Exemptions, Rule 1401]

177-1 The operator shall set and maintain the fuel injection timing of the engine at 4 degrees retarded relative to standard timing.

[Rule 2005]

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Ammonia Storage Tanks

144-1 The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.

[Rule 1303-BACT]

157-1 The operator shall install and maintain a pressure relief valve set at 25 psig.

[Rule 1303-BACT]

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Appendix A

Facility Maximum and Expected Capacity

Source: AFC, January 2000, pg. 1-7, Table 1.3-1

	Max Output with Duct Burner Firing & Evap Cooling at 30° F Ambient and 60% RH, MW		Max Output with Duct Burner Firing & Evap Cooling at 59° F Ambient and 60% RH, MW		Expected Output with Duct Burner Firing & Evap Cooling at 82° F Ambient and 34% RH, MW	
	Gross	Net	Gross	Net	Gross	Net
4 Gas Turbines	702.8	included below	666.8	included below	638.8	included below
2 Steam Turbines	418.4	included below	418.4	included below	417.4	included below
Subtotal	1,121.2	1,090.9	1,085.2	1,055.9	1,056.2	1,027.7
2 Existing Boilers	138.0	132.0	138.0	132.0	138.0	132.0
Total	1,259.2	1,222.9	1,223.2	1,187.9	1,194.2	1,159.7

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Appendix B

Modeling Analysis

Modeling Summary

The applicant performed an initial screening level model to determine the worst case operating scenario for the gas turbines based on various operating loads and ambient conditions. This worst case scenario for the gas turbines was then used in the refined modeling, along with emissions from other equipment on site as appropriate. The following table shows, for the refined modeling, which equipment was included in the model for each applicable regulation:

Regulation	Modeled Emissions
NSR	New turbines/duct burners' emissions only
PSD	All new NO2 emitting equipment including gas turbine/duct burners and diesel engines
CEQA*	Facility-wide emissions, including gas turbine/duct burners, diesel engines, existing boilers 1 and 2, and cooling towers
1401 HRA	Facility-wide emissions of carcinogenic and toxic pollutants, including gas turbine/duct burners, diesel engines, existing boilers 1 and 2, and cooling towers

* Emissions during the construction phase were also modeled for CEQA purposes.

For purposes of AQMD permitting requirements, only NSR, PSD, and Health Risk Assessment model results are considered. The entire facility and construction impacts model under CEQA fall under CEC jurisdiction.

Emission Factors and Stack Parameters for Modeling Inputs

The following summaries reference the permit application support document when referring to appendices and tables.

1) Gas Turbines

As noted above, a screening analysis was performed on the turbines to determine the worst case impacts. A total of 10 scenarios were modeled (as shown in Appendix G, Table G.5.1. The results show that maximum impacts from the turbines occur at the following conditions (Appendix G, Table G.5.2):

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- 100% load
- duct burners on
- evaporative cooler off
- 30° F, 60% relative humidity

with the following corresponding stack parameters:

Parameter	Value
Exhaust temperature	359.67 K
Stack diameter	5.486 m
Exhaust flow	469.88 m ³ /s
Exit velocity	19.88 m/s

These conditions result in the following emission factors

Pollutant	Emissions
NOx	2.5 ppm, 2.24 g/s
CO	6.0 ppm, 3.26 g/s
SO2	0.25 gr/100 scf fuel, 0.18 g/s
PM10	0.00175 gr/scf, 1.39 g/s

These emission rates were then used in the refined modeling runs to determine the short-term impacts (i.e. 1 hour impacts). Long term annual NOx impacts were based on a NOx concentration of 2 ppm, about 1.8 g/s. These emission rates were used along with emissions for the other equipment on site as follows:

2) Diesel Generator

The emergency diesel generator emissions are based on results of a 30 minute test conducted at 50% engine load. The tested emissions are about _ of the manufacturer maximum emissions. Annual emissions are based on 200 hr/yr operation. Following are the emissions used in the modeling [Appendix G, Table G.3.7]:

Pollutant	Emissions		
	lb/hr	g/s short term	g/s annual
NOx	19.80	2.5	0.057
SOx	0.44	5.56E-02	1.27E-03
CO	1.56	0.2	0.004
VOC	1.56	0.2	0.004
PM10	0.81	0.1	0.002

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Stack parameters used for the emergency diesel generator are:

Parameter	Value
Exhaust temperature	710.6° F
Stack diameter	18 in
Exhaust flow	15,469 cfm
Exit velocity	44.47 m/s

3) Fire pump engine

The emergency fire pump engine emissions are based on manufacturer maximum data, with annual emissions based on 200 hr/yr operation, as follows [Appendix G, Table G.3.7]:

Pollutant	Emissions		
	g/bhphr	g/s short term	g/s annual
NO _x	4.94	0.250	5.70E-03
SO _x	n/a	0.008	1.81E-04
CO	1.31	0.066	1.51E-03
VOC	0.77	0.039	8.89E-04
PM10	0.25	0.013	2.89E-04

Stack parameters used for the fire pump engine are:

Parameter	Value
Exhaust temperature	890° F
Stack diameter	3 in
Exhaust flow	745 cfm
Exit velocity	77.10 m/s

3) Cooling Towers

The existing cooling towers' (units 1 and 2) PM10 emission rates are based on the design flow rate for each tower of 38,700 gpm, a typical drift rate factor of 0.02 from AP-42, and the total dissolved solids (TDS) sewer discharge limit of 490 ppmw. The calculated emissions using these criteria are 0.0239 g/s per cell, with a total of 10 cells per cooling tower. The existing cooling towers will be upgraded as part of the new installation, and will also begin to use reclaimed water instead of clean water. Therefore, future emissions from the towers were also calculated based on the new design and reclaimed water use,

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with the results being 0.024 g/s per cell, with 4 cells per tower. [Appendix G, Table G.3.4]

The new cooling tower emissions (units 3 and 4) are based on the design rate of 147,000 gpm per tower, a drift rate of 0.0006%, and a TDS level of 6,617 ppmw (reclaimed water). This results in an emission rate of 0.037 g/s per cell, with a total of 10 cells per tower. [Appendix G, Table G.3.6]

4) Existing Boilers

The existing boiler emissions were estimated based on the average of 2 source tests performed in June 1999, the results of which showed emission of about 0.140 lbs/mmbtu. It was then assumed that the addition of control equipment would reduce NO_x from the boilers to a level of 0.048 lbs/mmbtu (about 70%). Although there is no control on the boilers now, Mountainview intends to modify the boilers with some form of NO_x control, and they currently have applications in for water injection, FGR, and SCR for the boilers. Hourly emissions are calculated based on maximum heat input rate of 680 mmbtu/hr. Annual emissions for long term impacts are estimated assuming 24 hr/day operation. Below is a summary:

Pollutant	Emissions
	lbs/hr
NO _x	32.640
SO _x	0.680
CO	2.040
VOC	0.680
PM10	0.204

The assumed controlled mass emissions are roughly equivalent to a concentration of 50 ppm NO_x and 5 ppm CO. Previous tests of these boilers had shown emissions of NO_x in the 80-90 ppm range, while typical boiler CO emissions can range from 50-200 ppm.

Results of the refined modeling are presented in Table 6.8-39 on page 6.8-85.

The applicant also conducted specialized modeling analyses for fumigation, gas turbine start-up, and gas turbine commissioning.

Fumigation Modeling

Fumigation modeling was conducted using SCREEN3 for one turbine, with the results multiplied by four to determine total impact from all turbines. Results are in Appendix G, Table G.5.4.

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Modeling for Start-Up Emissions

Mountainview estimates that there will be 233 hot starts, 96 warm starts, and 36 cold starts of the turbines throughout the year. In other words, some form of start-up is anticipated to occur every day of the year making start-ups not a “special case”, but a normal operating scenario.

Since the turbines’ HRSGs will be kept hot with steam from the existing boilers, most of the start-ups are anticipated to be “hot.” A hot start is defined as lasting 1 hour, with the turbine being shut down (i.e. no steam to the HRSG) for 8 hours or less. Warm starts last 2 hours, and cold starts last 3 hours. A warm start would occur if no steam had been provided to the HRSG for 8-48 hours, while a cold start means more than 72 hours without steam flow through the HRSG.

Modeling for gas turbine start-up impacts were conducted assuming two turbines in start-up mode and two turbines operating at full load. According to the applicant, only two turbines will be in start-up mode at any one time. Emission factors for start-ups were calculated based on source test data from similar turbines during start –up (page 6.8-82). The emission factors are presented in Appendix G, Table G.3.5a, b. Exhaust characteristics for start-up were based on minimum operating load point (50%), and are presented in Table 6.8-38, page 6.8-84. Below is a summary:

Pollutant	Emission Rate (g/s)
NOx	2.5
SOx	0.1
CO	12.6
Stack Parameter	Value
Temperature	355 K
Velocity	12.6 m/s

The existing boilers will be operated to provide steam to the turbines’ HRSGs during start-up of the first set of turbines. This will allow the SCR catalyst temperatures to be maintained so that use of the SCRs can occur during start-ups to minimize turbine NOx emissions. Mountainview estimates the amount of steam provided to the turbines is equivalent to an approximate heat input rate of 52 mmbtu/hr. After the first set of turbines are running at normal load, the second set may be brought on-line. However, Mountainview estimates that steam from the first two turbines will be sufficient to maintain catalyst temperature for the second set of turbines, precluding further use of the boilers at that point for start-up purposes. The facility is still investigating the need for using the duct burners along with the existing boilers during start-up of the first set of turbines, although, at this time, they do not anticipate the need to fire the duct burners.

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Results of Fumigation and Start Up Modeling

Pollutant	Averaging Time	Significant Change in Air Quality Concentration	Model Results Start Up ^(a)	Model Results Fumigation ^(a)
NO ₂	1-hour	20 ug/m ³	18.6 ug/m ³	6.3 ug/m ³
CO	1-hour	1.1 mg/m ³	85.3 ug/m ³	9.3 ug/m ³
	8-hour	0.5 mg/m ³	-----	6.5 ug/m ³

a Includes gas turbines and duct burner emissions

Gas Turbine Commissioning

Emissions during gas turbine commissioning activities will be higher than under normal operation because the SCR and CO catalyst systems will not yet be installed, and the turbine combustors will not be tuned for optimal performance. The turbine commissioning impacts will be short term (< 6 months). The applicant evaluated 2 scenarios during commissioning to determine the impacts from the higher emissions. Under the first scenario, NO_x emissions were assumed to be 18 ppm or 128 lbs/hr, and CO emissions were estimated at 902 lbs/hr. Under the second scenario, it was assumed that the turbines would operate at 50% load. NO_x emissions were estimated at 100 ppm, or 432 lbs/hr, and CO emissions were 9 ppm, or 24 lbs/hr for this scenario. The results from the screening model were used to determine impacts for the 2 scenarios as discussed on pages 6.8-84 through 6.8-86.

Results of Turbine Commissioning Emissions Model

Pollutant	Averaging Time	Most Stringent Air Quality Standard	Mountainview Model Results	Significant Change in Air Quality Concentration	Mountainview Model Results
NO _x	1-hour	500 ug/m ³	423 ug/m ³	20 ug/m ³	141 ug/m ³
CO	1-hour	23 mg/m ³	9.5 mg/m ³	1.1 mg/m ³	296 ug/m ³

PSD Analysis

The applicant conducted visibility modeling including a regional haze analysis and coherent plume impact analysis. For these models, emission rates used were identical to

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those used in the other modeling analysis, as listed in Table G.5.3. (discussion on pages 6.8-93 through 96).

Health Risk Assessment

A Health Risk Assessment was performed to determine the maximum carcinogenic and toxic impacts from the facility. Emission factors used in the analysis are presented in Tables 6.9-3 and 6.9-4 on pages 6.9-7 through 6.9-10, with additional information presented in Appendix H. The emission for the turbines, emergency generator and fire pump engine were based on ARB's CATEF database factors along with the maximum hourly and annual fuel use levels. For the cooling towers, emissions were estimated using the maximum concentrations of toxic air contaminants expected in the cooling water, along with maximum hourly and annual cooling tower operating levels. Results are discussed on pages 6.9-12-13.

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Appendix C

Emissions During Turbine Commissioning

	Maximum Hourly and Daily Emissions During Commissioning				
	NOx	CO	VOC	SOx	PM10
Maximum Hourly Emissions	189	411	7	2	22
Maximum Daily Emissions	2,265	4,931	83	20	264
Total Emissions (lbs) (Note 1)	69,284	223,158	4447	1391	14,256

Note 1 Includes all 4 turbines combined

The following tests will be performed during commissioning:

- Full Speed No Load Tests (FSNL)

These tests will occur over approximately 5 days, with turbine load at about 400 mmbtu/hr, or 20% of full load. There will be no SCR or CO catalyst installed, and the DLN burner may not be fully optimized. NOx emissions can be as high as 100 ppm during these tests, and CO emissions may be as high as 385 lbs/hr.

- Part Load Test

These tests will occur over a 6 day period, with turbine load at about 1,160 mmbtu/hr, or 60% of full load. Again, there will be no SCR or CO catalyst control, and NOx emissions may be as high as 100 ppm during these tests, and CO emissions up to 385 lbs/hr.

- Full Load Test (SCR not operational)

These tests will occur over a 4 day period at 100% turbine load. Although there will not be SCR control, the DLN should provide some NOx control. NOx concentrations are expected to be in the range of 18 ppm. The CO catalyst will be installed and operational, and CO emissions are expected to be at 6 ppm.

- Full Load Tests (SCR partial operation)

These tests will occur at 100% turbine load over a 5 day period, for the purpose of SCR optimization. NOx emissions can be expected to be 18 ppm or less, with CO emissions at 6 ppm.

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- Full Load Tests (SCR Operational)

These tests will occur over a 13 day period for the first turbine and a 1 day period for the second turbine. The tests will be run at full turbine load, and the NOx concentrations should be at or near the levels expected during normal operation, with CO emissions again at 6 ppm.

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Appendix D

Turbine Carcinogenic and Toxic Emission Estimates

Emissions of the following pollutants are calculated using the emission factors from CARB CATEF database (except ammonia, which is based on 5 ppm slip), in conjunction with maximum hourly and annual fuel consumption rates. The following emissions are per turbine.

Pollutant	Emission Factor	Emissions		
	lbs/mmcf	lbs/hr	lbs/day	tons/yr
benzene	1.36E-02	2.7E-02	6.48E-01	1.18E-01
formaldehyde	1.10E-01	2.18E-01	5.23	9.55E-01
PAH's	6.60E-04	1.0E-03	2.4E-02	4.38E-03
acetaldehyde	6.86E-02	1.36E-01	3.26	5.96E-01
ammonia		13.46	323.04	58.95
naphthalene	1.66E-03	3.0E-03	7.2E-02	1.31E-02
hexane	2.59E-01	0.513	12.3	2.25
acrolein	6.43E-03	1.3E-02	3.12E-01	5.69E-02
propylene oxide	4.78E-02	9.5E-02	2.28	4.16E-01
propylene	7.70E-01	1.526	36.62	6.68
toluene	7.10E-02	1.41E-01	3.38	6.18E-01
xylene	2.61E-02	5.2E-02	1.25	2.27E-01
1,3 butadiene	1.27E-04	3.0E-04	7.2E-03	1.31E-03

Fuel Consumption Rates:

Hourly: 2.11 mmcf/hr
Annual: 18,484 mmcf/yr

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Appendix E

Heat Input Rates and Estimated Fuel Consumption

	30°F, 60% RH		102°F, 18% RH	
	Heat Input mmbtu/hr	Fuel Use mmcf/hr	Heat Input mmbtu/hr	Fuel Use mmcf/hr
Gas Turbine	1991	1.98	1838	1.83
Duct Burner	131	0.13	135	0.13
Total	2122	2.11	1973	1.96

Note:

Fuel consumption based on fuel HHV of 1005 btu/scf

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Appendix F

Units 3 and 4 (new turbines) Cooling Tower Emissions

1. Cooling Tower PM10 Emissions

Flow Rate (gal/min)	147,000
Drift Rate (%)	0.0006
Drift per Tower (gal/min)	0.882
Drift per Tower (lbs/hr)	441.35
TDS level (ppmw)	6,617
PM10 per tower (lbs/hr)	2.290
PM10, Total 2 towers (tpy)	24.52

2. Cooling Tower Carcinogenic and Toxic Emission Estimates

Pollutant	Concentration in Cooling Tower Recirculation Water	Emission Rates	
	ppmw	lbs/hr ⁽¹⁾	tons/yr
Barium	1	4.41E-04	1.85E-03
Cadmium and compounds	0.01	4.41E-06	1.85E-05
Chromium III	0.05	2.21E-05	9.26E-05
Copper and compounds	0.07	3.09E-05	1.30E-04
Hydrogen cyanide	0.2	8.83E-05	3.71E-04
Lead and compounds	0.05	2.21E-05	9.26E-05
Manganese and compounds	0.07	3.09E-05	1.30E-04
Mercury and compounds	0.002	8.83E-07	3.71E-06
Phenol	0.175	7.72E-05	3.24E-04
Sulfates	3350	1.48E+00	6.21E+00
Zinc	0.175	7.72E-05	3.24E-04

(1) lbs/hr based on drift rate per tower of 441.35 lbs water per hour

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Appendix G

Emission Estimates - Fuel Use Basis

Emissions of VOC, PM10, and SOx are estimated on a lb/mmcf basis using maximum emission rates in lbs/hr and the maximum fuel use estimates. These emission factors will be used along with monthly fuel use data for determination of compliance with the monthly offset limits. NOx emissions are also estimated in lbs/mmcf for RECLAIM reporting purposes. For the commissioning period, NOx emissions are based on a concentration of 18 ppm (twice DLN guarantee of 9 ppm). For the interim reporting period, NOx is based on the DLN combustor guarantee of 9 ppm. Verification of monthly CO emissions will be through the use of CEMS.

Pollutant	Maximum Emission Rate	Maximum Fuel Use	Emission Factor
	lbs/hr	mmcf/hr	lbs/mmcf
NO _{xcomm} (1)	127.94	2.11	60.7
NO _{xinterim} (2)	63.97	2.11	30.3
VOC	3.47	2.11	1.64
PM10	11.0	2.11	5.21
SOx	1.42	2.11	0.67

- (1) Based on 18 ppm NOx concentration
- (2) Based on 9 ppm NOx concentration

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Appendix H

NSPS Calculations

Since turbine rating is greater than 100 mmbtu/hr, use:

$$\text{STD} = 0.0075 \frac{14.4}{Y} + F$$

Where:

STD = allowable NOx emissions in percent volume at 15%, dry

Y = manufacturer's rating in KJ/watt-hr

F = 0 for natural gas with a nitrogen content < 0.015%w

Y = (1991 x 10⁶ Btu/hr) X (1/171 X 10⁶ W) X (1055 joules/btu) X (KJ/1000 J)

Y = 12.28 KJ/Watt-hr

$$\begin{aligned} \text{STD} &= 0.0075(14.4/12.28) + 0 &= 0.00879 \\ & &= 87.9 \text{ ppm} \end{aligned}$$

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Appendix I

30 Day Average Emission Calculations

Example calculations:

CO:

20 hrs cold starts X 100 lbs/hr	=	2,000 lbs/month
8 hrs warm starts X 62.5 lbs/hr	=	500
3 hrs cold starts X 50 lbs/hr	=	150
689 baseload hours X 8.65 lbs/hr	=	5959.85
Total	=	8609.85 lbs/month
	=	287.00 lbs/day

VOC:

720 baseload hours X 3.47 lbs/hr	=	2498.4 lbs/month
	=	83.28 lbs/day

SOx:

720 baseload hours X 1.42 lbs/hr	=	1022.4 lbs/month
	=	34.08 lbs/day

PM10:

PM10 emissions are limited by the offsets provided by the applicant. Mountainview both purchased PM10 offsets, and will also use excess SOx credits for PM10 at a 2 to 1 ratio as follows:

Purchased PM10	942 lbs/day		
Purchased SOx	755		
Used SOx	164		
SOx Remaining for PM10	$(755-164)/2$	=	295
Total Available PM10	$942 + 295$	=	1237 lbs/day
1237/4 turbines/1.2	=		257.7 lbs/day

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However, because offsets are based on rounded-up whole numbers $258 \text{ lbs/day} \times 1.2 = 310 \times 4 = 1240 \text{ lbs/day}$ required offsets for all 4 turbines, which is more than Mountainview provided. Therefore, emissions will be limited to $257.49 \text{ lbs/day/turbine} \times 30 \text{ days/month} = 7725 \text{ lbs/month}$, and required offsets are then: $257 \times 1.2 = 308 \times 4 = 1232 \text{ lbs/month}$.